Executive Summary

OECD

Projected Costs of Generating Electricity

2010 Edition

International Energy Agency

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Nuclear Energy Agency

Projected Costs of Generating Electricity

2010 Edition

INTERNATIONAL ENERGY AGENCY
NUCLEAR ENERGY AGENCY
ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

Executive summary

Projected Costs of Generating Electricity – 2010 Edition presents the main results of the work carried out in 2009 for calculating the costs of generating baseload electricity from nuclear and fossil fuel thermal power stations as well as the costs of generating electricity from a wide range of renewable technologies, some of them with variable or intermittent production. All of the included technologies are expected to be commissioned by 2015. The core of the study consists of individual country data on electricity generating costs. However, the study also includes for the first time extensive sensitivity analyses for key cost parameters, since one of the objectives is to provide reliable information on key factors affecting the economics of electricity generation using a range of technologies. This new report in the series continues the now traditional representation of baseload generating costs made in order to compare the various types of generating plants within each of the countries represented and also to provide a basis for comparing generating costs between different countries for similar types of plant. The report can serve as a resource for policy makers, researchers and industry professionals seeking to better understand the power generation costs of different technologies.

The study focuses on the expected plant-level costs of baseload electricity generation by power plants that could be commissioned by 2015. It also includes the generating costs of a wide range of renewable energy sources, some of which have variable output. In addition, the report covers projected costs related to advanced power plants of innovative designs, namely commercial plants equipped with carbon capture, which might reach the level of commercial availability and be commissioned by 2020.

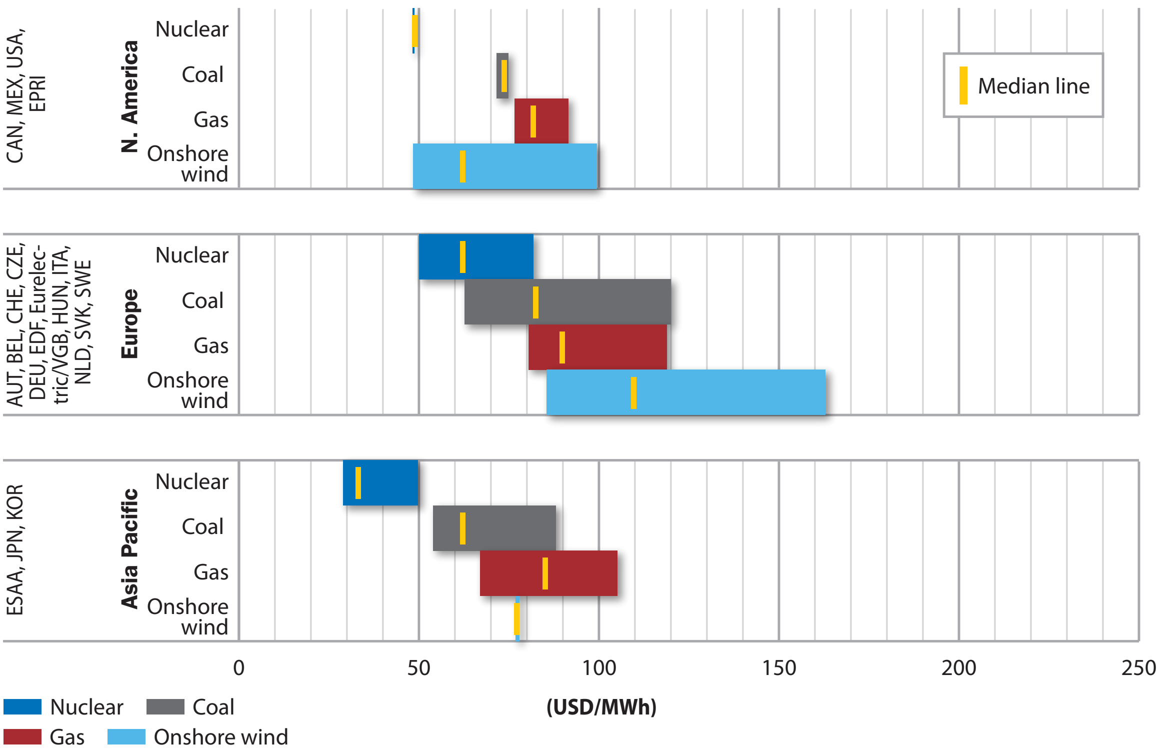
The study was carried out with the guidance and support of an ad hoc Expert Group of officially appointed national experts, industry experts and academics. Cost data provided by the experts were compiled and used by the joint IEA/NEA Secretariat to calculate the levelised costs of electricity (LCOE) for baseload power generation.

The calculations are based on the simple levelised average (unit) lifetime cost approach adopted in previous studies, using the discounted cash flow (DCF) method. The calculations use generic assumptions for the main technical and economic parameters as agreed upon by the ad hoc Expert Group. The most important assumptions concern the real discount rates, 5% and 10%, also keeping with tradition, fuel prices and, for the first time, a carbon price of USD 30 per tonne of CO_2.[1]

1. See Chapter 2 on "Methodology, conventions and key assumptions" for further details on questions of methodology and Chapter 7 on "Financing issues" for a discussion of discount rates. It needs to be kept in mind that the LCOE methodology deals with financial costs only and does not include any social or external costs of electricity production.

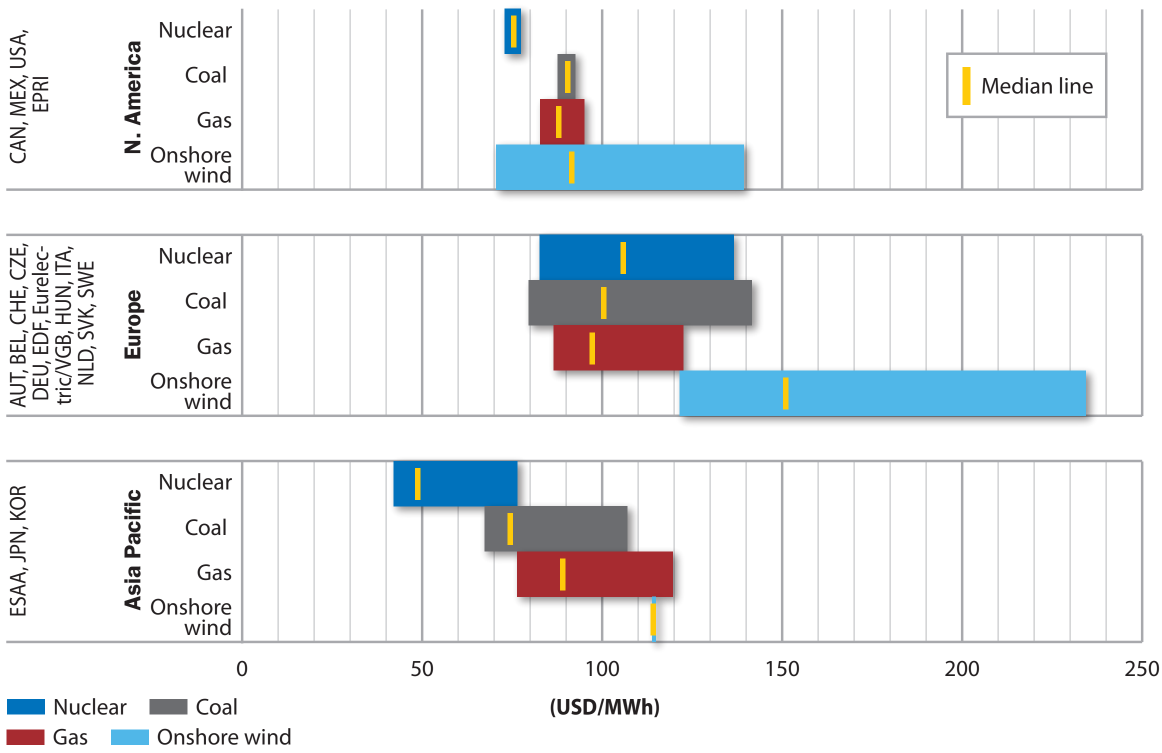
The study reaches two important conclusions (see Figures ES.1 and ES.2 below). First, in the low discount rate case, more capital-intensive, low-carbon technologies such as nuclear energy are the most competitive solution compared with coal-fired plants without carbon capture and natural gas-fired combined cycle plants for baseload generation. Based on the data available for this study, where coal is low cost (such as in Australia or certain regions of the United States), both coal plants with and without carbon capture [but not transport or storage, referred to as CC(S)] are also globally competitive in the low discount rate case. It should be emphasized that these results incorporate a carbon price of USD 30 per tonne of CO_2, and that there are great uncertainties concerning the cost of carbon capture, which has not yet been deployed on an industrial scale.

Figure ES.1: Regional ranges of LCOE for nuclear, coal, gas and onshore wind power plants
(at 5% discount rate)



Second, in the high discount rate case, coal without carbon capture equipment, followed by coal with carbon capture equipment, and gas-fired combined cycle turbines (CCGTs), are the cheapest sources of electricity. In the high discount rate case, coal without CC(S) is always cheaper than coal with CC(S), even in low-cost coal regions, at a carbon price of USD 30 per tonne. The results highlight the paramount importance of discount rates and, to a lesser extent, carbon and fuel prices when comparing different technologies. The study thus includes extensive sensitivity analyses to test the relative impact of variations in key cost parameters (such as discount rates, construction costs, fuel and carbon prices, load factors, lifetimes and lead times for construction) on the economics of different generating technologies individually considered.

Figure ES.2: Regional ranges of LCOE for nuclear, coal, gas and onshore wind power plants
(at 10% discount rate)



Features of the method of calculation

The study includes 21 countries and gathered cost data for 190 power plants. Data was provided for 111 plants by the participants in the Expert Group representing 16 OECD member countries (Austria, Belgium, Canada, Czech Republic, France, Germany, Hungary, Italy, Japan, Korea, Mexico, Netherlands, Slovak Republic, Sweden, Switzerland and United States), for 20 plants by 3 non-member countries (Brazil, Russia and South Africa) and for 39 plants by industry participants [ESAA (Australia), EDF (France), Eurelectric (European Union) and EPRI (United States)]. In addition, the Secretariat also collected data for 20 plants under construction in China using both publicly available and official Chinese data sources.

The total sample comprises 34 coal-fired power plants without carbon capture, 14 coal-fired power plants with carbon capture [referred to in the study as coal with CC(S)], 27 gas-fired plants, 20 nuclear plants, 18 onshore wind power plants, 8 offshore wind plants, 14 hydropower plants, 17 solar photovoltaic plants, 20 combined heat and power (CHP) plants using various fuels and 18 plants based on other fuels or technologies. The data provided for the study highlight the increasing interest of participating countries in low-carbon technologies for electricity generation, including nuclear, wind and solar power, CHP plants as well as first commercial plants equipped with carbon capture, all key technologies for decarbonising the power sector.

The electricity generation costs calculated are plant-level (busbar) costs, at the station, and do not include transmission and distribution costs. Neither does the study include other systemic effects such as the costs incurred for providing back-up for variable or intermittent (non-dispatchable) renewable energies. For the calculation of the costs of coal-fired power generation with carbon capture, only the costs of capture net of transmission and storage have been taken into account. Finally, the cost estimates do not include any external costs associated either with residual emissions other than CO_2 emissions or impacts on the security of supply.

A number of key observations can be highlighted from the sample of plants considered in this study. A first issue is the wide dispersion of data. The results vary widely from country to country; even within the same region there are significant variations in the cost for the same technologies. While some of this spread of data reflects the timing of estimates (costs rose rapidly over the last four years, before falling late in 2008 and 2009), a key conclusion is that country-specific circumstances determine the LCOE. It is clearly impossible to make any generalisation on costs above the regional level; but also within regions (OECD Europe, OECD Asia), and even within large countries (Australia, United States, China or Russia), there are large cost differences depending on local cost conditions (e.g. access to fossil fuels, availability of renewable resources, different market regulations, etc.). These differences highlight the need to look at the country or even sub-country level.[2]

A second issue relates to the quality of data itself. High-quality data is needed to produce reliable figures. However, the widespread privatisation of utilities and the liberalisation of power markets in most OECD countries have reduced access to often commercially sensitive data on production costs. Data used in this study is based on a mix of current experience, published studies or industry surveys. The final cost figures are subject to uncertainty due to the following elements:

- Future fuel and CO_2 prices: it is important to note that for the first time a price of carbon for all OECD countries is internalised and included in LCOE calculations. Policies to reduce greenhouse gas emissions have reached a level of maturity such that members of the Expert Group decided that a carbon price of 30 USD per tonne of CO_2 was now the most realistic assumption for plants being commissioned in 2015. Nevertheless, the group underlines the uncertainties connected to this assumption.
- Present and future financing costs.
- Construction costs.
- Costs for decommissioning and storage, which particularly affect nuclear energy, still remain uncertain due to the relatively small experience base, noting that the DCF methodology employed in the study means that decommissioning costs become negligible for nuclear at any realistic discount rate.
- In an indirect manner, the results of the study also depend on future electricity prices since the LCOE methodology presupposes stable electricity prices that fully cover costs over the life of a power plant. A different electricity price assumption would yield different results.

The current edition of *Projected Costs of Generating Electricity* has been produced in a period of unprecedented uncertainty given the current economic and policy context, characterised on the one hand by the growing momentum of climate change policies as well as uncertainty about the timing of the impact of policy measures and, on the other hand, by the dramatic changes in economic conditions affecting both energy demand and supply.

2. In particular, the cost for renewable energy technologies shows important variations from country to country and, within each country, from location to location. In addition, some of the largest current markets for renewable energy are not represented in the study.

In addition to the uncertainties described above, there are also other factors which cannot be adequately incorporated into a cross-country analysis but need to be acknowledged, and are therefore dealt with in the study in a qualitative manner in dedicated boundary chapters:

- integrating variable and intermittent renewable energies in most existing electricity systems;
- current cost of capital for energy projects and differences in tax treatment;
- issues in connection with the behaviour of energy markets (demand and price risk);
- cost of CC(S), a technology that can be key for the decarbonisation of the power sector, yet is still in the development stage.

Increased uncertainty drives up costs through higher required returns on investment/discount rates, and this applies to *all* electricity generating technologies. However, higher discount rates penalise more heavily capital-intensive, low-carbon technologies such as nuclear, renewables or coal with CC(S) due to their high upfront investment costs, and comparatively favour fossil-fuel technologies with higher operating costs but relatively lower investment costs, especially gas CCGT. For renewable technologies, site-specific load factors can also be decisive. Overall, however, access to financing and the stability of the environmental policy frameworks to be developed in the coming years will be crucial in determining the outcome of the successful decarbonisation of the power sector.

Main results

With all the caveats inherent to the EGC methodology, *Projected Costs of Generating Electricity* nevertheless enables the identification of a number of tendencies that will shape the electricity sector in the years to come. The most important among them is the fact that nuclear, coal, gas and, where local conditions are favourable, hydro and wind, are now fairly competitive generation technologies for baseload power generation.[3] Their precise cost competitiveness depends more than anything on the local characteristics of each particular market and their associated cost of financing, as well as CO_2 and fossil fuel prices.[4] As mentioned earlier, the lower the cost of financing, the better the performance of capital-intensive, low-carbon technologies such as nuclear, wind or CC(S); at higher rates, coal without CC(S) and gas will be more competitive. There is no technology that has a clear overall advantage globally or even regionally. Each one of these technologies has potentially decisive strengths and weaknesses that are not always reflected in the LCOE figures provided in the study.

Nuclear's strength is its capability to deliver significant amounts of very low carbon baseload electricity at costs stable over time; it has to manage, however, high amounts of capital at risk and its long lead times for construction. Permanent disposal of radioactive waste, maintaining overall safety, and evolving questions concerning nuclear security and proliferation remain issues that need to be solved for nuclear energy.

3. The variable nature of wind power, in contrast to conventional, dispatchable technologies, requires flexible reserves to be on hand for when the resource is not available. Thus, the wind cost is higher at the level of the system than at the level of the plant, although our analysis of integration studies (see Chapter 7) suggests that this additional cost is not prohibitive. System costs are likely to be lower in larger markets, with a geographical spread of plants, and when wind is part of a complementary portfolio of other generation technologies.

4. Other renewable energies are for the time being outside this range, although significant cost reductions are expected with larger deployment, in particular for solar PV as intermediate load.

Coal's strength is its economic competitiveness in the absence of carbon pricing and neglecting other environmental costs. This applies in particular where coal is cheap and can be used for generating electricity close to the mine, such as in the western United States, Australia, South Africa, India and China. However, this advantage is markedly reduced where significant transport or transaction costs apply, or where carbon costs are included. The high probability of more generalised carbon pricing and more stringent local environmental norms thus drastically reduce the initial cost advantage.

Carbon capture [CC(S)] has not yet been demonstrated on a commercial scale for fossil-fuelled plant. The costs provided in the study refer to carbon capture at plant level [CC(S)]; an unproven rule of thumb says that transport and storage might add another USD 10-15 per MWh. Until a realistic number of demonstration plants have been operated for worthwhile time frames, total CC(S) costs will remain uncertain.

The great advantage of *gas-fired power* generation is its flexibility, its ability to set the price in competitive electricity markets, hedging financial risk for its operators and its lower CO_2 profile; on the other hand, when used for baseload power production it has comparatively high costs given the gas price assumptions (except at high discount rates) and is subject to security of supply concerns in some regions. Progress in the extraction of lower-cost shale gas has eased the supply and demand balance and therefore improved the competitive outlook for natural gas in North America, where prices are around half those based on oil-indexation in Continental Europe or the OECD Asia-Pacific region.

For the first time, *onshore wind* is included among the potentially competitive electricity generation sources in this edition of *Projected Costs of Generating Electricity*. On the basis of the dynamics generated by strong government support, onshore wind is currently closing its still existing but diminishing competitiveness gap. Its weakness is its variability and unpredictability, which can make system costs higher than plant costs, although these can be addressed through geographic diversity and an appropriate mix with other technologies. According to the data available for this study, offshore wind is currently not competitive with conventional thermal or nuclear baseload generation. Many renewable technologies, however, are immature, although their capital costs can be expected to decline over the next decade. Renewables, like nuclear, also benefit from stable variable costs, once built.

If *Projected Costs of Generating Electricity* is any indication, the future is likely to see healthy competition between these different technologies, competition that will be decided according to national preferences and local comparative advantages. At the same time, the margins are so small that no country will be able to insulate its choices from the competitive pressures emanating from alternative technology options. The choices available and the pressure on operators and technology providers to offer attractive solutions have never been greater. In the medium term, investing in power markets will be fraught with uncertainty.

Coal-fired generating technologies

Most coal-fired power plants in OECD countries have overnight investment costs ranging between 900 and 2 800 USD/kWe for plants without carbon capture.[5] Plants with carbon capture have overnight investment costs ranging from 3 223 to 6 268 USD/kWe. Coal plants with carbon capture are henceforth referred to as "coal plants with CC(S)" in order to indicate that their cost estimates do not include the costs for storage and transportation.

5. Overnight construction costs include owner's cost, EPC (engineering, procurement and construction) and contingency, but exclude interests during construction (IDC). Total investment costs include IDC, but exclude refurbishment or decommissioning.

Construction times are approximately four years for most plants. From the data provided by respondents, the prices of both black coal and brown coal vary significantly from country to country. Expressed in the same currency using official exchange rates, coal prices can vary by a factor of ten. The study assumed a black coal price of USD 90 per tonne except for large coal-producing countries that are partly shielded from world markets such as Australia, Mexico and the United States, where domestic prices were applied. For brown coal, domestic prices were applied in all cases.

With a carbon price of 30 USD/tonne, the most important cost driver for coal plants without CC(S) is the CO_2 cost in the low discount rate case. In the case of coal plants equipped with CC(S), the construction cost is the most important cost driver in the low discount rate case. In the high discount rate case, where total investment cost is more important, variations in the discount rate, closely followed by construction costs, are key determinants of total costs for both coal plants with and without CC(S).

At a 5% discount rate, levelised generation costs in OECD countries range between 54 USD/MWh (Australia) and 120 USD/MWh (Slovak Republic) for coal-fired power plants both with and without carbon capture. Generally, investment costs and fuel costs each represent around 28%, while operations and maintenance (O&M) costs account for some 9% and carbon costs around one-third of the total.

At a 10% discount rate, the levelised generation costs of coal-fired power plants in OECD countries range between 67 USD/MWh (Australia) and 142 USD/MWh (Slovak Republic) also for plants both with and without carbon capture. Investment costs represent around 42% of the total, fuel costs some 23%, O&M costs approximately 8% and carbon costs 27% of the total LCOE.

Gas-fired generating technologies

For the gas-fired power plants without carbon capture in the OECD countries considered in the study, the overnight construction costs in most cases range between 520 and 1 800 USD/kWe. In all countries considered, the investment costs of gas-fired plants are lower than those of coal-fired and nuclear power plants. Gas-fired power plants are built rapidly and, in most cases, expenditures are spread over two to three years. The O&M costs of gas-fired power plants are significantly lower than those of coal-fired or nuclear power plants in all countries which provided data for the two or three types of plants considered. The study assumed prices of USD 10.3/MMBtu in OECD Europe and USD 11.7/MMBtu in OECD Asia. National assumptions were assumed for large gas-producing countries such as Australia, Mexico and the United States.

At a 5% discount rate, the levelised costs of generating electricity from gas-fired power plants in OECD countries vary between 67 USD/MWh (Australia) and 105 USD/MWh (Italy). On average, investment cost represents only 12% of total levelised costs, while O&M costs account for 6% and carbon costs for 12%. Fuel costs instead represent 70% of the total levelised cost. Consequently, the assumptions on gas prices used in the study are the driving factors in the estimated levelised costs of gas-generated electricity.

At a 10% discount rate, levelised costs of gas-fired plants in OECD countries range between 76 USD/MWh (Australia) and 120 USD/MWh (Italy). The difference between costs at a 5% and a 10% discount rate is very limited due to their low overnight investment costs and short construction periods. Fuel cost remains the major contributor representing 67% of total levelised generation cost. Investment costs amount to 16%, while O&M and carbon costs contribute around 5% and 11% respectively to total LCOE.

Nuclear generating technologies

Cost figures for nuclear power plants vary widely reflecting the importance of national conditions and the lack of recent construction experience in many OECD countries. For the nuclear power plants in the study, the overnight construction costs vary between 1 600 and 5 900 USD/kWe with a median value of 4 100 USD/kWe. The study considered different Generation III technologies including the EPR, other advanced pressurised water reactor designs as well as advanced boiling water reactor designs.

At a 5% discount rate, the levelised costs of nuclear electricity generation in OECD countries range between 29 USD/MWh (Korea) and 82 USD/MWh (Hungary). Investment costs represent by far the largest share of total levelised costs, around 60% on average, while O&M costs represent around 24% and fuel cycle costs around 16%. These figures include costs for refurbishment, waste treatment and decommissioning after a 60-year lifetime.

At a 10% discount rate, the levelised costs of nuclear electricity generation in OECD countries are in the range of 42 USD/MWh (Korea) and 137 USD/MWh (Switzerland). The share of investment in total levelised generation cost is around 75% while the other cost elements, O&M costs and fuel cycle costs, represent 15% and 9% respectively. Again, these figures include costs for refurbishment, waste treatment and decommissioning after a 60-year lifetime.

Renewable generating technologies

For onshore wind power plants, the specific overnight construction costs are in the range of 1 900 to 3 700 USD/kWe. The expense schedules reported indicate a construction period between one to two years in the majority of cases. As with all other technologies, the costs calculated and presented in this report for wind power plants are plant-level costs. They therefore do not include specific costs associated with the integration of wind or other intermittent renewable energy sources into most existing electric systems and, in particular, the need for backup power capacities to compensate for the variability and limited predictability of their production.

The levelised costs of electricity produced with onshore wind and solar PV technologies exhibit a very high sensitivity to the load factor variation, and to a lesser extent to the construction cost, at any discount rate. In contrast with nuclear and thermal plants with a generic load factor of 85%, plant-specific load factors were used for renewable energy sources. For variable renewable sources such as wind, the availability of the plant is in fact an important driving factor for the levelised cost of generating electricity. The reported load factors of wind power plants range between 21% and 41% for onshore plants, and between 34% and 43% for offshore plants except in one case.

At a 5% discount rate, levelised generation costs for onshore wind power plants in OECD countries considered in the study range between 48 USD/MWh (United States) and 163 USD/MWh (Switzerland), and from 101 USD/MWh (United States) to 188 USD/MWh (Belgium) for offshore wind. The share of investment costs is 77% for onshore wind turbines and 73% for offshore wind turbines.

At a 10% discount rate, the levelised costs of wind-generated electricity in OECD countries range between 70 USD/MWh (United States) and more than 234 USD/MWh (Switzerland). For offshore wind turbines the costs range from 146 USD/MWh (United States) to 261 USD/MWh (Belgium). The share of investment costs is 87% for onshore wind turbines and 80% for offshore wind turbines. For the latter, the difficult conditions of the marine environment imply a higher share of the costs for operations and maintenance.

For solar photovoltaic plants, the load factors reported vary from 10% to 25%. At the higher load factor, the levelised costs of solar-generated electricity are reaching around 215 USD/MWh at a 5% discount rate and 333 USD/MWh at a 10% discount rate. With the lower load factors, the levelised costs of solar-generated electricity are around 600 USD/MWh.

The two reported solar thermal plants have a load factor of 32% (Eurelectric) and 24% (US Department of Energy). The levelised costs range from 136 USD/MWh to 243 USD/MWh, for 5% and 10% discount rates respectively.

The current study also contains limited data on the cost of hydroelectric power generation. Depending on the plant size and specific site, hydro is competitive in some countries; however, costs vary so widely that no general conclusions can be drawn.

Conclusions

The levelised costs and the relative competitiveness of different power generation technologies in each country are highly sensitive to the discount rate and slightly less, but still significantly sensitive, to the projected prices for CO_2, natural gas and coal. For renewable energy technologies, country- and site-specific load factors also play an important role.

With the liberalisation of electricity markets, certain risks have become more transparent, so that project proponents must now bear and closely manage these risks (to the extent that they can no longer be transferred to consumers or taxpayers). This has implications for determining the required rate of return on generating investments. Access to financing and national support policies for individual technologies designed to reduce financing risks (such as feed-in tariffs, loan or price guarantees) are thus likely to play an important role in determining final power generation choices.

Environmental policy will also play an increasingly important role that is likely to significantly influence fossil fuel costs in the future and the relative competitiveness of various generation technologies. In addition, the markets for natural gas are undergoing substantial changes on many levels which make current projections for prices even more uncertain than usual. Also, coal markets are being influenced by new factors. Security of energy supply remains a concern for most OECD countries and may be reflected in government policies affecting generating investment in the future.

This study provides insights into the relative costs of generating technologies in the participating countries and reflects the limitations of the methodology and the generic assumptions employed. The limitations inherent in this approach are stressed in the report. In particular, the cost estimates presented do not represent the precise costs which would be calculated by potential investors for any specific project. Together with national energy policies favouring or discouraging specific technologies, the investors' concern about risk is one of the reasons explaining the difference between the study's findings and the market preference for gas-fired technologies. Different fuel price expectations may also affect investors' decisions in some markets.

Within this framework and various limitations, the study suggests that no single electricity generating technology can be expected to be the cheapest in all situations. The preferred generating technology will depend on a number of key parameters and the specific circumstances of each project. This edition of *Projected Costs of Generating Electricity* indicates that the investors' choice of a specific portfolio of power generation technologies will most likely depend on financing costs, fuel and carbon prices, as well as the specific energy policy context (security of supply, CO_2 emissions reductions, market framework).